Responses to the Hawaii Renewable Energy Alliance's Information Requests

HREA-HECO-FIR-1

The paragraph 1 on page 1 reads as follows: "The HECO Companies can support competitive bidding for certain forms of new generation, but only if it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be mitigated or eliminated, and only if appropriate exceptions are recognized."

Please provide three examples of when, given the above criteria, competitive bidding would be an acceptable approach to HECO for acquiring new resources.

HECO Response:

One example of when competitive bidding could be an acceptable approach to HECO for acquiring new resources would be where a solicitation is made by the utility for renewable energy resources in order to stimulate the addition of cost-effective renewable energy in Hawaii, promote viable projects that will integrate positively with the utility grids, and encourage renewable energy generation activity where such is lacking in targeted categories. Renewable Hawaii Inc. ("RHI") released round 1, phased renewable energy request for project proposals ("RE RFPP") in 2003 and 2004 for Oahu, then Maui, Molokai and Lanai, and finally Hawaii. RHI released a second round of the RE RFPP in March 2005. Please refer to HECO's response to CA-HECO-IR-5.

Another example of when competitive bidding could be an acceptable approach to HECO for acquiring new resources would be where a solicitation is made by the utility for renewable energy resources in an attempt to meet renewable energy set-asides that may be included in future IRP plans. As HECO stated in its submission, dated September 26, 2005, to the Commission on comments relating to the Commission's RPS Second Concept Paper, "it appears that the utility can establish "set-asides" as part of its IRP Plan for resources that will allow the utility to obtain the designated attributes, as long as the set asides do not arbitrarily exclude other resources that would provide the same attributes."[1]

A third example of when competitive bidding could be an acceptable approach to HECO for acquiring new resources would be where at least all of the following conditions are met:

(a) The Commission has determined that competitive bidding is an appropriate mechanism for acquiring or building new generating capacity in Hawaii;

(b) The Commission has established a competitive bidding framework and competitive bidding guidelines;

(c) The host utility is allowed play a major role in the competitive bidding process including: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible;

(d) The competitive bidding process takes into account all costs associated with each bid to ensure all bids are fairly and equitably evaluated, as explained in HECO's Final SOP, Section 3, pages 20 to 22;

(e) The competitive bidding process takes into account Hawaii-specific factors, such as (1) the very limited number of sites that are available to site new generation, and the difficult, time-consuming and uncertain process that must be followed to change land use designations in Hawaii in order to acquire new sites for generation, (2) the

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[1] Page 14 of HECO's submission. The Second Concept Paper is dated July 26, 2005 and relates to Economists Incorporated's "Proposals for Implementing Renewable Portfolio Standards in Hawaii."

extended time that must be allotted to conduct the necessary environmental review for, and to permit and obtain the necessary approvals for, new generation, (3) the utility and island-specific constraints that constrain the size of new generation that can be added to the systems, (4) the limited fuel options that are economically available in Hawaii, and other factors, such as location, transmission access/cost of system upgrades, operational flexibility, financial impact, in-service date flexibility, and fuel supply access into the RFP and evaluation process;

(f) An IRP cycle has been completed to the extent that the timing, type and size of an increment of capacity has been determined;

(g) There is sufficient time to acquire the needed increment of capacity through a competitive bidding process;

(h) The resource is not the expansion or repowering of existing company units and is not a CHP unit.

HREA-HECO-FIR-2

Regarding the discussion of Hawaii specific factors that HECO raises in paragraph 3, page 2:

HREA would agree, in general, that there are a limited number of sites available in our island for large facilities, especially on Oahu. However, we see at least two ways to mitigate this potential problem:

1. Utility-Identified Site. Assuming the utility has identified a site for a new generation facility and has either purchased the land or secured a lease for access to the site, could not the site be made available for competitive bids? For example, assume further that the utility identifies the value of the land (lease or purchase) in the RFP. Then, if the winning bidder was NOT the utility, could not the utility either lease or sell the land (as appropriate) to the winning bidder? If not, why not?

2. Size-and-Location Factors. Would HECO agree that another potential strategy would be to consider multiple facilities of smaller sizes? For example, if HECO specified in the RFP that they desired a 100 MW class conventional facility, a bidder might propose four 25 MW facilities dispersed in locations that could be easier to site, especially they incorporated biofuels.

HECO Response:

1. As described in response to CA-HECO-IR-1, HECO currently owns new generating station sites on the islands of Oahu and Maui. The utility should have the discretion to offer these and future, utility-controlled sites to developers in a competitive bidding process. For example, if the utility is soliciting bids for a turnkey option, it may be appropriate for the utility to offer its site because the utility will eventually own and operate the plant. Such discretion will also maximize the utility's flexibility to tailor an RFP to best meet changing system needs, or to possibly facilitate the development of particularly desirable supply-side resources, such as renewable energy technologies which can be highly dependent upon site location with limited site alternatives (e.g., wind energy and pumped storage hydro). (See also HECO's response to PUC-IR-53.)

HECO emphasizes that there are several disadvantages to mandating that the utility offer its site during the competitive bidding process. First, utility-controlled sites are valuable assets that have been secured to benefit the customers over the long term. To ensure long-term reliability of supply, it may be beneficial for the utility to maintain site control to ensure power generation resources could be constructed to meet system reliability requirements. This is particularly true in Hawaii, where the number of sites that are available to site new generation are very limited. Second, offering utility-controlled sites may reduce the flexibility of the utility to perform crucial parallel planning for a utility-owned option to backup the unfulfilled commitments of IPP developers of generation. Hawaii utilities do not have the option to acquire power from other jurisdictions, or even other islands. Third, offering utility-controlled sites may reduce the full value hoped to be gained in a competitive solicitation process. Bidders are not encouraged to develop creative options to meet Hawaii's needs, but instead will be more likely to select the utility site possibly limiting the range of resources options bid. For example, a pumped storage hydro developer may decide not to bid if a utility-controlled site located, for illustration purposes, in Campbell Industrial Park was made available in the RFP. And fourth, there may be complex legal issues associated with the sale or lease of a utility-controlled site, such as ensuring that the bidder and not the utility absorbs any environmental liability associated with the site. (See HECO's response to PUC-IR-53.)

In addition, the challenges of having a 3rd-party use a utility site should not be overlooked. In general, locating non-utility generators ("NUG") on utility sites would need to be assessed on a case-by-case basis to examine the factors that could make it difficult to do so. Specific physical and technical parameters of the NUG installation such as the technology to be installed, space and land area requirements, topographic slope and geotechnical constraints or recommended limitations, fuel logistics, water requirements, number of site personnel, access requirements, waste and emissions from operations, noise profile, electrical interconnection requirements, physical profile, etc., would need to be provided by the NUG in order for the utility to evaluate the feasibility of the installation. Other factors that would need to be assessed include how the operation, maintenance and construction of each installation would affect:

- maintaining security of the site;
- land ownership;
- land use and permit considerations (compatibility of the proposed development on present and planned land uses);
- existing and new environmental permits and licenses;
- impact on operations and maintenance of existing and future facilities; and
- impact to the surrounding community
- change in zoning permit conditions
- safety of utility personnel.

2. There could be pros and cons to installing multiple facilities of smaller sizes. Fossil-fueled facilities of less than 5 MW may not be required to prepare an Environmental Impact Statement, and generally, the permitting schedule would be reduced. On the other hand, dozens of smaller facilities could be required, and while each facility could be easier to implement, the sum total of facility-specific tasks would not be trivial. While the outcome of the ongoing Distributed Generation docket (No. 03-0371) cannot

be predicted, the HECO utilities long-term resource plans have included a mix of both central-station generation and distributed generation supply-side resources, in addition to demand-side resources.

Specific to HREA's scenario in which (four) 25 MW facilities are proposed, a facility for 25 MW is not small for the HECO Companies' systems. For example, Hawaii's PGV facility is on the order of 30 MW, while Lanai's Miki Basin facility and Molokai's Palaau Station are each less than 12 MW. It should not be assumed that new facilities of similar size would be easy to site. Four 25 MW facilities could require four environmental impact statements (instead of just one for one 100 MW facility). In addition, renewable facilities are not necessarily easier to site than fossil-fueled facilities, as evidenced by the recent experience with the proposed Kahe wind farm project.

With regard to the potential use of biofuels in electric power generating units, HECO has initiated a multi-phased program to assess technical feasibility and economic viability. The projected phases of the program include: (1) investigation of biofuel supply, availability, pricing, and properties; (2) evaluation of generating unit performance and emissions; (3) investigation of key operational, environmental, and regulatory issues faced by HECO; and (4) demonstration of biofuel usage in utility power generating units. The University of Hawaii has completed Phase 1 (investigate biofuel supply, availability, pricing, and properties) of HECO's biofuels assessment program. For Phase 2, HECO has executed a contract with the Southwest Research Institute to evaluate the performance and emissions of a combustion turbine combustor fired with biofuel blends.

It was determined in Phase 1 that biodiesel (fatty acid methyl esters produced from waste oils or oil crops) and ethanol from sugars (grain alcohol produced from fermented sugars) are the most promising liquid biofuel candidates due to potential reliability of supplies, compatibility with existing generating units and existing fuels, accessibility by existing generation units, and cost. Although more detailed investigations are needed to confirm actual potentials, a better understanding of the properties and potential availability of biodiesel, ethanol, and blends with No. 2 fuel oil (diesel) was gained through the Phase 1 investigation.

HREA-HECO-FIR-3

The following is from paragraph 5.d. on page 3:

> *"Utilities have the obligation to serve their customers while IPPs who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility."*

If the PPA for an IPP has provisions to meet emergency and other contingency requirements, given appropriate coordination with the utility and perhaps financial incentives, please explain how IPP facilities would constrain the utility's operating flexibility?

<u>HECO Response:</u>

Please refer to HECO's Final Statement of Position, Exhibit I. This issue is described in detail on the bottom of page 4 through the bottom of page 8.

HREA-HECO-FIR-4

The following is from paragraph 6. on page 5:

> *"If the utilities will have to restructure their balance sheets and increase their percentage of more costly equity financing in order to offset the impacts of purchasing power on their balance sheets, then this rebalancing cost must also be taken into account in evaluating the total cost of the new generating unit."*

Would the above statement be true if there were no fixed payments to IPPs, i.e. only variable payments based on the delivery of capacity and energy?

HECO Response:

The utilities may need to restructure their balance sheets and increase equity financing to offset the impacts of purchasing power even if there are no fixed payments to IPPs. Some examples of how this might happen are:

1) Consolidation required under Financial Accounting Standards Board Interpretation No. 46 (revised December 2003) ("FIN 46R").

   Under FIN 46R, entities meeting certain specific criteria are deemed "variable interest entities" ("VIE"). If an entity is determined to be a VIE, a determination must be made as to whether there is a "primary beneficiary". The "primary beneficiary" is the enterprise that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both. The primary beneficiary must consolidate the VIE. FIN 46R could potentially require that the purchaser (the utility) under a power purchase agreement, consolidate the seller (the IPP). If the utility must consolidate the IPP in its financial statements, investors' assessments of the utility's risks as a result of the PPA may change. Consolidation of an IPP may have a negative impact on how the investment community views the utility's risk profile. If there is a negative impact, the utility may have to take mitigating action to reduce its own debt and infuse equity to rebalance its capital structure.

2) Capital lease treatment under Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease" ("EITF 01-8") and Financial Accounting Standards Board Statement No. 13, "Accounting for Leases" ("FAS 13").

EITF 01-8 specifies tests to be applied to an arrangement (ie. the PPA) to determine whether or not the arrangement contains a lease and specified the circumstances under which an arrangement should be evaluated to determine whether or not it contains a lease. If the PPA is determined to be a lease, the lease must further be evaluated under FAS 13 to determine whether the lease is a capital lease or an operating lease. If the PPA is a capital lease, the payments must be evaluated to determine whether they meet the minimum lease payment criteria. If the payments are determined to meet the criteria for minimum lease payments, the purchaser would report the present value of the minimum lease payments as an investment in asset, related depreciation, a capital lease obligation and related interest expense. A capital lease obligation is a form of debt. To offset the increase in debt resulting from a capital lease, the utility may need to reduce its other debt and infuse equity to rebalance its capital structure. If the payments are not considered minimum lease payments, there is no lease asset and no lease obligation to record for financial reporting purposes; however there may be imputed debt implications. Similarly, if the lease is determined to be an operating lease, there is no lease asset and no lease obligation; however, there may be imputed debt implications.

3) Imputed debt by the credit rating agencies.

The credit rating agencies have determined that certain obligations that are not currently reported as liabilities for financial reporting purposes should be reflected as debt in the ratios used to evaluate a company's risk profile. In order to capture the debt-like features of PPAs, the credit rating agencies calculate "imputed debt." "Imputed debt" negatively impacts financial ratios. A company can offset the negative impact of imputed debt by increasing its equity and decreasing its other debt.

We are aware of two areas which one of the major credit rating agencies, Standard & Poors, currently imputes debt for HECO: 1) fixed payments associated with PPAs and 2) expected payments under operating leases. Our understanding is that S&P will evaluate payments associated with PPAs to access the debt-like nature of the payments. For example, a PPA with a provision that requires the utility to take the output would be considered more debt-like than one that allowed the utility to determine what output it will take. Further, if payments are expected, even if they are not fixed, they may be deemed debt-like, and may result in imputed debt (similar to the way operating leases are evaluated by the credit rating agencies).

HREA-HECO-FIR-5

On page 5, regarding the discussion on how long it would take to do a competitive procurement, assuming that HECO continues it's planning activities on the identified Campbell Industrial Park site and facility (i.e., 100 MW class combustion turbine) and assuming further:

1. In January 2006, HECO is required by the PUC to solicit bids (using HECO's best procurement practices) for the desired facility;
2. A RFP is released by June 2006, including an offer to potential bidders to purchase or lease HECO's site;
3. A successful IPP bidder is selected by June 2007 to build and operate the facility (perhaps with a turnkey option and/or a buyout option);
4. The utility will transfer approved project permits to the successful bidder; and
5. Assist the bidder in obtaining permits still in process.

HECO Response:

This information request contains a number of hypothetical assumptions without an associated question.

Implementation of the hypothetical would result in substantial delay in the addition of the combustion turbine to HECO's system. For example, the conclusion of the competitive bid process would include the negotiation and approval of a power purchase agreement with the winning bidder. The winning bidder would then have to implement the project, which would include obtaining financing, ordering equipment, and arranging for contractors, in addition to completing the permitting process. At the end of the process, HECO would have acquired peaking capacity through a power purchase agreement, which generally would not be desirable, and would lose control of the site that it requires for other purposes.

HECO also would have far less flexibility to change the manner in which the facility is used, or the fuels that are burned. At present, the CT is being designed so that alternate fuels can be used when they become available.

The hypothetical also illustrates why the utility generally would not want to make its sites available to an IPP. First, HECO's tank farm is located on the site. HECO could not lease the site without first subdividing it, and providing separate access to the tank farm. Second, HECO would lose control of the site where it has the flexibility to add additional generation if necessary to meet load growth, or as part of the contingency plan to back-up other IPP projects, or for other reasons. See response to HREA-HECO-FIR-2.

HREA-HECO-FIR-6

The first sentence of paragraph 7.d. (page 6) reads as follows:

> *"The competitive procurement process for distributed generation ("DG") should be different than the competitive procurement process for generation that provides power directly to the utility or sells power to the utility."*

Would HECO agree with the following?

1. DG on the utility-side of the meter should be incorporated with all utility supply-side procurements? Specifically, while generally being smaller in capacity and dispersed on the utility's grid, DG can provide capacity and energy to the utility.
2. DG on the customer-side of the meter should be incorporated with all utility demand-side procurements? Specifically, customer-sited DG serves primarily to reduce or offset customer load and therefore are demand-side measures.

HECO Response:

1. DG at HECO substation sites should be utility-owned or utility-leased. HECO's position on competitive procurement of CHP is addressed in the DG Docket. Please refer to HECO's Opening Brief in Docket No. 03-0371, Section I.D.1, pages 22 to 24.
2. The question is not clear as to what HREA means by "utility demand-side procurements." If HREA is asking whether or not HECO agrees that customer-sited DG are demand-side management measures, then HECO disagrees. HECO has responded to this and similar questions (which were posed by HREA). HECO has consistently responded that DG differs from DSM measures and programs. Please refer to HECO's response to HREA-HECO-IR-12 and HREA-HECO-IR-13 in the instant docket. Please also refer to Docket No. 03-0371 ("DG Docket") and the Rebuttal Testimony of Mr. Scott Seu, pages 42 to 48; HECO's responses to HREA-HECO-IR-8, HREA-HECO-RT-1-IR-19, HREA-HECO-RT-1-IR-20, and HREA-HECO-RT-1-IR-22; and HECO's Opening Brief, pages 59 to 63.

In addition, as HECO stated on page 15 of its Final Statement of Position, in footnote 6, "This docket was opened to address competitive bidding for new generation. Thus, competitive bidding for DSM resources is clearly beyond the scope of this docket. In fact, the acquisition of DSM resources is the subject of the energy efficiency docket opened by the PUC, Docket No. 05-0069."

HREA-HECO-FIR-7

The first sentence of paragraph 7.e. (page 6) reads as follows:

> *"As-available renewable energy generation has different characteristics than firm capacity, and the timing of when such resources are added to the utility's system is not nearly as important to the reliability of the system."*

By "different characteristics" is HECO implying that it will continue *not* to recognize the reliability contributions of as-available renewable energy sources and *not* make capacity payments, which are within the intent and spirit of PURPA, for wind, solar and hydro?

HECO Response:

HECO objects to this question on the grounds that it is argumentative in characterizing HECO's position with respect to contracting with wind, solar and hydro resources. Without waiving its objections, HECO provides the following response.

HECO contrasted the different characteristics of as-available generation and firm capacity in response to HREA-HECO-IR-2.

With respect to the reliability contributions of as-available renewable energy sources, HECO stated in response to HREA-HECO-IR-2 that "[a]s-available resources can contribute to system reliability, especially when there is a firm capacity shortfall." Please also see HELCO's Opening Brief in Docket No. 00-0135 (Apollo Energy Corporation), Section II.C.1, on pages 11 and 12. (Mr. Bollmeier submitted testimony in that docket.) Please also refer to HECO's submission, titled "Comments Relating to the RPS Technical Paper," dated October 14, 2005, associated with the Commission's Act 95 workshops relating to Renewable Portfolio Standards. In Section II.G., on page 38, HECO states "HECO notes under certain circumstances, intermittent resources [may] improve system reliability. On the other hand, intermittent resources generally do not allow the utility to defer or avoid firm capacity additions, and do not allow the utility to build less firm capacity. As-available energy suppliers do not have an obligation to deliver power in the amount needed and at the time needed." HREA has been participating in the Commission's workshops.

With respect to capacity payments for as-available resources, HECO has consistently stated its position in various Commission proceedings in which HREA (or Mr. Bollmeier) has participated. In Docket No. 00-0135 (Apollo Energy Corporation Petition), one of the issues pertained to capacity payments for the Apollo windfarm on the Island of Hawaii. Issue No. 1 in Prehearing Order No. 17804 was "[w]hether the proposed HELCO-Apollo Power Purchase Agreement ("PPA") should include a provision for capacity payments to Apollo, and if so, what capacity payments should be included in a HELCO-Apollo PPA?" In the Rebuttal Testimony of Mr. Thomas A. Wind on behalf of Apollo Energy Corporation[1], Mr. Wind indicated that "[a] rough estimate of this firm capacity from the existing wind turbines would be 2 MW. If the wind farm is repowered to 9.75 MW (7 MW maximum instantaneous) as proposed by Apollo, then I would estimate the firm capacity value to be 3 MW. If the Kamao'a Wind Farm is then expanded up to the 20 MW level (15 MW maximum instantaneous), then the firm capacity value would be about 6 MW."[2] Mr. Wind used a Midcontinent Area Power Pool ("MAPP") procedure for estimating the capacity value but acknowledged that "Kamao'a's historical hourly generation was not available to me; therefore, I could not calculate the equivalent firm capacity."[3]

HELCO's position was that "HELCO should not pay capacity payments for wind energy based on accredited capacity determined through the MAPP capacity accreditation process. While an accredited capacity number can be derived from the MAPP methodology, that number cannot be equated with a firm capacity amount that HELCO could rely upon to fulfill its

[1] Filed on September 15, 2000.
[2] Apollo RT-2, page 8, line 19, to page 9, line 3.
[3] Apollo RT-2, page 8, lines 17 and 18.

long-term obligations to provide firm power to its customers. In practice, even if an accredited capacity number can be calculated for a resource, consideration must be given to the output characteristics of the resource and whether or not a small, isolated electric utility should rely on this number for long-term capacity planning purposes. It would not be prudent to rely on an accredited capacity number for intermittent as-available energy generators to defer the construction of new capacity because the HELCO system is not interconnected with other utilities and thus cannot rely on neighboring utilities to provide needed capacity in the event as-available resources do not produce the amount of power needed at the time needed."[4]

In Decision and Order No. 18568, dated May 30, 2001, the PUC stated, "The commission does not believe that capacity payments for Apollo are warranted. Rather, HELCO, under its generation capacity planning criteria, is unable to avoid or defer the construction of its own generation additions as a result of the intermittent energy generated by a wind farm such as Kamaoa. Nor is HELCO able to avoid the fixed operations and maintenance costs associated with its own generation."

The PUC continued "The wind resource used by Apollo to generate energy is as-available. The generation of energy by wind farms such as Apollo is ultimately dependent upon the availability and strength of this resource. Apollo, the commission finds, is not under a continual obligation to supply power to HELCO upon demand."[5]

Please also refer to HECO's responses to COM-HECO-DT-IR-15, HREA-HECO-T-2-IR-3, HREA-HECO-T-3-IR-7 and COM-HECO-SIR-2 in Docket No. 03-0371 (DG Docket). HREA was a party to that docket.

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[4] Testimony of Ross Sakuda, HELCO RT-2, page 18, line 21, to page 19, line 9.
[5] Section III.A, page 4.

In addition, please refer to HECO's submission, titled "Comments Relating to the RPS Technical Paper," dated October 14, 2005, associated with the Commission's Act 95 workshops relating to Renewable Portfolio Standards. In Section II.G., on pages 38 to 43, HECO addresses the issue of capacity value of intermittent resources. HREA is a participant in the Commission's workshops.

Furthermore, HREA appears to be advancing an argument via this information request that part of the intent and spirit of PURPA is to provide capacity payments for as-available renewable energy sources. HECO does not find that either PURPA rules or the Commission's rules on "Small Power Producers" in Title 6, Chapter 74, state that capacity payments should be made for as-available renewable energy sources.

HREA-HECO-FIR-8

The first sentence of paragraph 9.d. (page 8) reads as follows:

> *"With regard to host utility self-build options, utilities have been selecting their own build options more frequently over the past few years for several reasons."*

HREA believes the basis for HECO's arguments for this conclusion lies primarily with experience on the mainland, and doesn't apply to Hawaii. Specifically:

1. If it were true that "the financial and credit problems faced by independent generators have led to higher debt costs and higher equity ratios for independent generators, virtually eliminating the competitive advantage once enjoyed by independent generators," why does the HECO family now have three windfarm IPPs with approved contracts and construction underway?

2. With respect to the second argument of transmission constraints, the above windfarms (as designed) do not have transmission constraints as alluded to as a significant issue by HECO. Furthermore, HREA's understanding is the windfarm operators are paying for transmission additions and upgrades; and

3. HREA does not believe same windfarm IPPs have "deteriorating credit quality," or is HECO suggesting that they do.

<u>HECO Response:</u>

1. First, while the HECO Companies (HECO, HELCO and MECO) have Power Purchase Agreements with three wind energy developers (Kaheawa Wind Partners, or "KWP," with MECO, and Hawi Renewable Development, or "HRD," and Apollo Energy Corporation, or "Apollo" with HELCO), only two of them (Kaheawa) are under construction. Construction on the Apollo project has not yet commenced.

   Second, in all three cases, none of the HECO Companies had utility self-build proposals to compete with the wind energy developers. Therefore, the HECO Companies did not have a self-bid option to compare to those of the wind energy developers. For example, the HECO Companies did not have access to the sites to develop the projects. KWP had control of the site above Maalaea on Maui to develop the 30 MW windfarm. HRD had control of the site in Hawi to develop its 10.56 MW windfarm on Hawaii. Apollo owns the site upon which it will repower its existing windfarm and add more wind generators to increase maximum wind generating capacity to 20.5 MW under the Power Purchase Agreement with HELCO.

Third, in the particular cases of KWP, HRD and Apollo, the HECO Companies do not have information on their debt and equity positions on their projects. So the HECO Companies do not know if the IPPs have higher debt costs and higher equity ratios than the HECO Companies.

Fourth, HREA's "beliefs" as to the basis for HECO's arguments are irrelevant to the discussion.

2. There is no question posed in this part of the information request. However, HECO disagrees with HREA's statement that no transmission constraints were identified for the HRD, KWP, and Apollo wind farm projects. For each of these wind farm projects, operational performance limits, power factor requirements, and ride-through requirements were identified in interconnection studies and incorporated into their respective power purchase agreements, among other reasons, to ensure proper operation of the transmission system. These operational requirements are necessary to address the impacts of the wind farms on the Companies' systems.

3. By "same windfarm IPPs," HECO is interpreting this to refer to KWP, HRD and Apollo. As stated in HECO's response to part 1. above, the HECO Companies do not have information on their debt and equity positions on their projects. The HECO Companies do not know whether or not these IPPs have "deteriorating credit quality."

HREA-HECO-FIR-9

In paragraph 10.a to 10.d. (page 9) HECO describes four steps that it "could take to avoid self-dealing or concern over an unfair completive advantage that may be perceived by other bidders." Please respond to the following:

1. "The utility could submit its self-build option to the Public Utility Commission one day in advance of receipt of other bids. The utility could also provide substantially the same information as other bidders. By sending its proposal to the Commission in advance other bidders would be ensure that the utility could not adjust its bid price or project structure after reviewing other proposals." We would agree that this approach could mitigate against the utility's taking advantage of information provided in other proposals. However, we do not consider this step by itself to be persuasive in preventing utility self-dealing.

2. "The utility could establish a web-site devoted to disseminating information to all bidders at the same time, including the utility self-build option." We see this proposal as a "red herring." First, HECO would have intimate knowledge of the technical, cost and other requirements well in advance of the release date of information on a web-site. Specifically, how else would HECO be able to prepare the information for the web-site? Thus, this step would provide other bidders with little confidence that the utility is at the same place on the ball field as the rest of the bidders at the time of the release of the information. Consequently, HREA believes this step does little to reduce the perception of "self-dealing."

3. "The utility could use an independent observer to review the solicitation process including communications with bidders, bid evaluation and selection, and contract negotiations, and report to the PUC at various steps of the process." Again this is a "red herring," as HECO's position is that HECO should be the one to hire the independent observer and the observer would report to them. By definition, we do not believe the independent observer in this case could truly be considered "independent." Consequently, HREA believes this step does little to reduce the perception of "self-dealing."

4. "The Commission would then approve the result of the process by approving the commitment of expenditures for uility–owned generation and/or the power purchase agreement ("PPA") for generation owned by IPPs." This suggestion is at least a "pink herring." We believe the only way this step would reduce the perception of "self-dealing" would be to have an Independent Observer, hired by the Commission and reporting to the Commission, to ensure that:

    a. The entire solicitation was conduced in a "fair and open" process, and

    b. If HECO or an affiliate of HECO was allowed to bid, HECO did not take unfair advantage of its position.

However, we do not see how item "b" could be confirmed unless the Independent Observer was able to verify and ensure that:

i. A separate utility project team was tasked with *both* the preparation and evaluation of the RFP and this team was be *totally independent* of the "proposal and implementation" team, and

ii. The utility agreed that the Observer would be *totally independent* of the utility (per our proposal for the Observer would hired by the Commission and report to the Commission).

However, since HECO has not agreed on items "i" and "ii" above, this proposed step does little to reduce the perception of "self-dealing."

Therefore, our overall assessment is that only step 1 is plausible given the HECO's current position and, thus, step 1 by itself does very little to reducing the perception of "self-dealing."

HECO Response:

HECO objects to this information request on the grounds that it does not ask a question, but instead is a discussion of HREA's position. The statements in quotes and underlined in HREA's information request represents the position of the HECO Companies. The single question posed by HREA in Item 2 in this information request (Specifically, how else would HECO be able to prepare the information for the web-site?) is interpreted by HECO to be rhetorical in nature. Without waiving its objection, HECO provides the following response:

HREA is reporting only selected aspects of the many options identified by HECO for addressing the potential concerns over self-dealing. (HECO discussed the utility's participation in the process in its Final SOP, Exhibit II, pages 15-22.) HREA's logic is also fundamentally flawed. HREA chooses to look at each of the four steps or options it identified separately, apparently assuming that each option is totally separate and can stand on its own without being related. HECO takes exception to that approach. First, HREA should consider HECO's proposals as a whole, not piecemeal. Second, HECO's proposals are consistent with industry standards for addressing such issues. Third, HREA either does not include all the options identified by HECO or misconstrues HECO's position.

Step 1, submission of a utility self-build option one day in advance of receipt of other bids, is common in the industry as a means of mitigating against the perception of self-dealing. As HREA notes, this is not the only step proposed by HECO.

Step 2, establishment of a website to communicate with bidders, is another option designed to ensure all bidders receive the same information at the same time, including the utility self-build and affiliate options. Again, this process is very common in other RFPs on the Mainland, and is viewed as another step for addressing the concerns over self-dealing by third-party bidders.

Step 3, utility retention of an Independent Observer if utility-built and owned, utility-owned turnkey facilities, or facilities owned by utility affiliates are included in an RFP process, is not uncommon in utility industry RFP's on the mainland. If an Independent Observer is to be used, it is not proposed that utility selection of the Independent Observer occur in a vacuum without input by the Commission on potential candidates for consideration. To the contrary, as explained on page 40 of Exhibit 1, the utility proposes to identify potential candidate consulting firms to serve as the Independent Observer and accept candidates provided by the Commission as well. The utility then may also seek the Commission's review of the candidate list and approval of the final list of candidates. Ultimately, selection of the Independent Observer by the utility would proceed from candidates on this list, selected per certain criteria that includes among others having a demonstrated track record of impartiality and ability to report candidly to the Commission.

In addition, on page 9 of the Final Statement of Position, HECO indicates that the role of the independent observer is to report to the Commission at various steps of the process. HECO has also noted that it is common for the independent observer to submit a report to the Commission on the process at the end of the process.

With regard to Step 4, whether the Commission retains an independent observer or not, the Commission has the ultimate responsibility to approve the resource selection decision. This decision will not rest with an independent observer, who will not and should not be liable or responsible for such a decision.

In addition to these options, HECO has identified a number of other steps to enable the process to proceed in a fair, comprehensive and open manner such that bidders have a substantial base of information to guide their proposal. These are identified on pages 39-41 of Exhibit I.

Finally, the purpose of competitive bidding is to facilitate the utility's acquisition of cost-effective generation resources, not to discourage utilities from owning and operating such resources. The purposes of competitive bidding do not include: (1) attempting to artificially "level" the playing field by increasing the risk of utility ownership of new generation (and therefore increasing the cost of utility ownership), or by otherwise handicapping utilities; or (2) by establishing a cumbersome, costly, inflexible competitive bidding process that ignores the practical needs of and constraints faced by small, island electric utility systems.

HREA-HECO-FIR-10

Paragraph 13.a. (page 11) reads as follows:

> *The IRP Plan can continue to be developed using the current process followed by the HECO Companies. In this case, the role of the IRP Plan should be to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP Plan can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs.*

While HREA supports the integration of competitive bidding with IRP, we continue to be concerned with how and when competitive bidding would be employed. Specifically, HECO proposes to select a "preferred resource plan" (which we interpret to be the 5-year action plan), then implement a competitive bidding process to select the winning bidders (utility or non-utility) to meet the 5-year action plan. Our biggest concern is that selection of a preferred resource (s), as currently pursued, is based primarily on utility performance and cost estimates of alternative facilities technologies. We have argued consistently that the implementation approach matters, and that we believe HECO's estimates are more typical of what it would cost the utility to build and operate the desired facilities.

Referencing the discussion on pages 17 to 20 of our Preliminary SOP, as updated on pages 18 to 22 of our Final SOP, we have proposed that a competitive bidding process be implemented to determine the most cost-effective approach to select the projects and activities to meet the 5-year plan objectives. Therefore, would HECO agree that?

1. Use of competitive bidding to identify and select the most cost-effective projects (and other measures if DSM is included) for meeting the 5-year plan objectives, assuming that PPAs are awarded in a timely manner to the winning bidders and/or a winning utility proposal is approved by the Commission;

2. The early use of competitive bidding as tool for selecting projects for the 5-year plan would likely be more efficient and effective than the current process. This approach would lead to earlier selection of projects and activities based on market prices rather than utility estimates. This would be both more efficient and effective; and

3. Ideally, in IRP it would be best to conduct an all-sources solicitation or separate demand-side and supply-side solicitations concurrently. Specifically, HECO could evaluate and select the most cost-effective projects or measures. In general, we would expect a number of demand-side measures to be more cost-effective and those selected would off-set a portion of the IRP-derived, capacity and energy load requirements. Supply-side resources could then be selected to supply the remaining load requirements.

HECO Response:

1. First, HREA's interpretation that the preferred resource plan is the five-year action plan is not correct. The preferred resource plan is the 20-year plan to meet the IRP objective of meeting near and long term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The five-year action plan is the schedule for implementation of the plan over a five-year period. As stated in the Commission's IRP Framework, in Section III.A.2., on pages 6 and 7, "The result of this [five-year plan development] process is a program implementation schedule or action plan. The schedule represents an implementation strategy or timetable for program implementation."

   Second, HECO does not agree with HREA's suggested approach. In its Final SOP, on page 18, HREA stated, "HREA supports the use of competitive bidding to select all projects and programs for the 5-year plan, rather than the current approach of identifying resources in the IRP process and pursuing implementation at a later time." HREA further stated on page 19, "Overall, whereas in the past, a number of alternative IRPs were generated from the committee inputs, HREA believes it will be more productive to go directly to the 'golden fleece' – the plan to meet our RPS law, mitigate energy and fuel supply risks and move us down the path to sustainable energy." HECO sees HREA's suggested approach as impractical and unworkable. Without the IRP process, there would be no context for the appropriate timing, amount or selection of resources. Also, the types of resources – demand-side and supply-side must be distinguished. HECO's position is that bidding of DSM resources is beyond the scope of consideration in this docket. (See HECO's response to HREA-HECO-FIR-6.) Furthermore, HECO stated that "Exceptions to any mandated competitive bidding process must be allowed when the competitive bidding process would not allow needed generation to be added in a timely fashion, and when another competitive procurement process would be more efficient." Please see HECO's Final SOP, Exhibit II, pages 5 to 10.

2. HECO assumes that HREA's reference to an "early use of competitive bidding" refers to the use of competitive bidding within the IRP cycle simultaneously, which was identified as the second method for conducting the IRP and competitive bidding process in HECO's Preliminary SOP, Exhibit A (pages 19 to 20). Under this approach, the IRP determines the need for capacity and the timing of need. The RFP is developed and issued during the IRP cycle. The integration phase of the IRP occurs with the evaluation phase of the RFP and uses the RFP bids in lieu of supply-side resource alternatives developed through the Supply-Side Resource Optimization ("SRO") process currently employed in IRP. The bids received are "run" through the IRP process like any generic unit or utility option. The IRP is based on the evaluation of the bids with a preferred plan and contingency plan identified. Contracts are negotiated with the winning bidders.

As stated in its Preliminary SOP, the disadvantage of this method is that developers may be unwilling to participate at an early stage in the process, or to freeze prices for the time required to complete the IRP process. While some developers may be willing to submit preliminary bids, they may not be meaningful and could be used to "game" the process since they will not be providing final bids in which the exact details of the project are identified and for which power purchase agreements would be signed. In addition, this second method limits the effectiveness of the IRP Advisory Group, who are exposed to confidentiality issues and disclosure issues associated with potential access to competitive intelligence in the RFP process. This approach is not typical of recent competitive bidding approaches.

3. HECO disagrees. Please see HECO's response to part 1 above and HECO's response to HREA-HECO-FIR-6.

HREA-HECO-FIR-11

On page 12, HECO discusses briefly alternative contracting options and "avoided costs of the generic resource identified in the IRP Plan or to the utility self-build project." Given that competitive bidding is likely to change the way HECO contracts for purchase power, we have the following questions:

1. When soliciting proposals in a competitive bidding process, does HECO believe it would be better to announce a "target" price based on avoided cost or some other measure?
2. Or would it be better to calculate a "target" price, but not reveal that price until the proposals have been submitted?
3. In the case of item 2, would HECO agree that price of the winning bidder (assuming that only one award is sought), becomes the "new" avoided cost? and
4. Regarding the type of contract, does HECO believe it would be prudent to retain some flexibility, e.g., a winning bidder could choose to contract as a QF (Qualifying Facility) or choose an alternate contract format?

HECO Response:

1. HECO's consultant, Mr. Selgrade, addressed this subject in the October 2005 RPS workshop. HECO does not believe it would be preferable to announce a target price based on avoided cost or some other measure when soliciting proposals in a competitive bidding process. The purpose of competitive bidding is to encourage competition among suppliers to achieve the lowest reasonable price. Establishing a target price defeats the purpose of bidding, because bidders may attempt to price up to the target rather than competing based on their own unique projects through a truly competitive process.
2. Calculating a target price and not revealing the price until the proposals have been submitted serves no direct purpose. The winning bidder will be selected based on the merits of its proposal, which will include price and non-price factors.

3. In many cases, the results of a competitive bidding process can serve as the basis for establishing the new avoided cost since the resource has presumably been selected based on a market test. This would not be the case if the Company conducted a targeted solicitation or select RFP for specific resources, such as renewable resources to meet the renewable portfolio standards.
4. Should competitive bidding be implemented, HECO has proposed developing and including a form of power purchase agreement to include in the RFP. This contract will serve as the basis for contract negotiation with the winning bidder.

HREA-HECO-FIR-12

The second and third sentences from paragraph 16 on page 13 read as follows:

> *"The HECO Companies themselves routinely use competitive procurement practices in acquiring and constructing utility equipment and facilities, and are experienced in issuing RFPs for major equipment purchases. HECO issued an RFP in 1987 that ultimately resulted in two major PPAs for firm capacity."*

Regarding the RFP in 1987:

1. Did HECO prepare a detailed set of specifications for the RFP based on HECO's planning activities?
2. If so, would HECO characterize the planning activities as a "backstop" proposal as discussed by the CA?
3. Would HECO characterize the results of the 1987 RFP as successful?

<u>HECO Response:</u>

1. HECO does not have all of the process and implementation documentation from its 1987 RFP, as explained in HECO's response to CA-HECO-IR-12, part a. Pages 4 through 7 of that IR response provide a summary of the events that led to the 1987 RFP.
2. HECO does not know all of the implications of the Consumer Advocate's "backstop" proposal, and asked clarifying questions of the Consumer Advocate in HECO/CA-FIR-13. HECO notes that parallel planning may be an option to mitigate risk, but can offset any hoped for cost savings that competitive bidding is perceived to provide. (See HECO's Final SOP, Exhibit I, at 8.)
3. It is not clear what HREA means by the term "successful". The results of the 1987 RFP speak for themselves. HECO's Purchase Power Alternatives Request for Proposal, issued on June 4, 1987, resulted in HECO entering into two purchase power agreements and the construction of two QF projects at oil refinery sites located at Campbell

Industrial Park. Exhibit III of HECO's Final Statement of Position describes HECO's experiences with Independent Power Producers.

HREA-HECO-FIR-13

The second sentence from paragraph 17 on page 14 reads:

> *"As is shown in Exhibit III, circumstances are substantially different now than they were in 1987, and are substantially different than they are on the mainland in terms of sites, fuels and other features that may make alternatives attractive."*

Regarding the circumstances since 1987:

1. In the case of the AES facility, one of the reported outages occurred in 1996 after problems on HECO's side, i.e., the Waiau-Koolau #1 line tripped, followed by the loss of Waiau #7 and Kahe 5 (reference HECO response to HREA-HECO-IR-09). Consequently, can HECO say definitively that IPP generators or more likely to fail than HECO's transmission lines and generators?

2. Problems reported by HECO with the HC&S facility on Maui were in 1988. Have there been any problems since then?

3. If MECO had spinning reserve could the problems attributed to the HC&S been avoided?

4. Regarding the problems in 2002 with the Puna Geothermal Ventures on Hawaii, would HECO agree that subsequent steps taken by PGV to expand their production wells should mitigate against similar occurrences in the future?

5. If HELCO had spinning reserve could the problems attributed to the PGV been avoided or was it also a matter that HELCO's reserve margins were low?

6. The other case was Hilo Coast Processing on Hawaii which reported in 1994 that it planned to shutdown in 1997 before the end of its contract. It is not clear from HECO's discussion whether the early demise of Hilo Coast actually caused any operational problems; and

7. Given that there is any number of occurrences possible on the utility or non-utility sides of the grid, why hasn't the HECO family moved to develop a spinning reserve policy on the outer islands?

<u>HECO Response:</u>

1. HECO does assess the reliability of both utility and IPP generating units, and also performs analysis to identify when improvements in transmission reliability are needed. Transmission line projects maintain or improve reliability and allow HECO to deliver

power to customers whether it is generated by utility or IPP generators. HREA is asking HECO if it has compared one type of entity (IPP generating units) with two types of utility entities (generating units and transmission lines). This apples to oranges comparison is not meaningful, and as a result, has not been performed by HECO.

2. In response to HREA-HECO-IR-9, HECO stated "In 1988, MECO experienced nine rolling blackouts on the island of Maui. By Order No. 9978, filed October 18, 1988, in Docket No. 6330, the Commission opened an investigation into, among other things, the cause or causes of the outages and MECO's plans and programs to prevent future rolling blackouts. As stated by MECO in Docket No. 6330, Hawaiian Commercial and Sugar Company's ("HC&S") failure to meet its firm commitment contributed to eight of the rolling blackouts Maui experienced in 1988. (In 1988, MECO and HC&S had a power purchase agreement dated July 31, 1980, which was approved in Decision and Order No. 6405, filed October 8, 1980, in Docket No. 4072.) (The operating restrictions placed by the Environmental Protection Agency on Maalaea Unit 12, which MECO had planned to place in service in April 1988, also contributed to the 1988 rolling blackouts.)"

On March 3, 1998, HC&S experienced a catastrophic failure at their Puunene Mill of the Turbo Generator No. 2, a 7.5 MW steam unit (10 MW with extraction), which destroyed the unit's steam turbine and generator. Since HC&S's TG-4 steam unit (15.0 MW, 20 MW with extraction) was also concurrently on-line undergoing repairs, HC&S was unable to provide their PPA-contracted firm capacity of 12 MW. When repairs on TG-4 were completed, it was returned to service on March 30, 1998, at which time HC&S was able to resume providing 12 MW firm capacity.

3. Where rolling blackouts occur, as in the case of MECO in 1988, there is not enough capacity to satisfy demand. When such events occur, there is no "spare" capacity to provide spinning reserve. Therefore, the rolling blackouts resulting from HC&S's inability to provide capacity when needed could not have been avoided by providing spinning reserve. There was not enough capacity to satisfy demand and consequently no spinning reserve was available.

4. HECO objects to this question on the grounds that it calls for speculation on the part of HECO in order to respond to the question. Without waiving any objections, HECO provides the following response. In response to HREA-HECO-IR-9, HECO stated "Puna Geothermal Venture's ("PGV's") normal rating is 30,000 kW. During 2001, PGV experienced changes in the characteristics of its steam source, and generally exported to HELCO between 22 MW and 28 MW at top load. In April 2002, PGV's normal top load rating was reduced to an average of 5.6 MW due to blockage of a source well and decreasing steam quality from another source well. The average rating for all of 2002 was 8.5 MW. In 2003, PGV's normal top load rating averaged 21 MW. In 2004, PGV generally exported between 25 and 26 MW."

   By "problems in 2002 with the Puna Geothermal Ventures" and "similar occurrences," HECO interprets the question to be referring to the blockage of a source well and decreasing steam quality. PGV has since completed drilling several new source wells. Whether or not any of the source wells will experience blockages in the future similar to that experienced in 2002 will depend on how well the wells are monitored and maintained or on some unforeseeable events. The future steam quality will depend on the nature of the resource and geotechnical factors.

5. HECO is unclear as to what specific "problems attributed to the PGV" HREA is referring to. In 2002, there were at least three instances where there was an interruption of service to a significant number of HELCO customers due to generation shortfalls which were due in part to the reduced output of PGV. Outages of the Hamakua Energy Partners power plant also contributed to the generation shortfalls in these instances. During these events, there was no "spare" generating capacity to provide spinning reserve.

6. It is not clear what HREA is referring to by the "early demise of Hilo Coast." The plant continued to operate through December 1994 and early 1995 under a temporary restraining order as HECO indicated in its response to HREA-HECO-IR-9. The plant continued to operate until the end of 2004.

7. First, HECO is unclear as to what HREA is referring to with respect to "any number of occurrences possible on the utility or non-utility sides of the grid." If HREA is referring to specific instances of generation shortfalls as described in HECO's responses above, then it would not be possible to carry spinning reserve when there is not enough capacity to satisfy demand.

   Second, as to why HELCO and MECO have not developed a spinning reserve policy, HREA posed this same question in Docket No. 03-0371 (DG Docket). Please refer to HECO's response to HREA-HECO-T-3-IR-6 in that docket.

HREA-HECO-FIR-14

Referring to the second paragraph on page 2 of Exhibit II to page 3, where HECO discusses a three-stage process to implement competitive bidding in Hawaii including integration with IRP:

1. Could not both stage 1 (basic guidelines) and stage 2 (framework provisions) be completed in this docket?
2. Is HREA correct in understanding that HECO is proposing to delay implementation of competitive bidding until the fourth round of the HECO IRP?

<u>HECO Response:</u>

1. The Commission opened the instant docket to evaluate the specific issues given in their Order No. 20583, dated October 21, 2003. It would be more appropriate for the Commission to issue its findings and conclusions on these issues before the second stage of developing framework provisions is commenced. (As HECO stated in its Final SOP, Exhibit II [page 2], the basic guidelines and framework provisions were sequentially done in the same docket because the parties were able to agree on guidelines for IRP in an initial stage of the docket.) The framework could be addressed in a subsequent phase of this proceeding, or in a separate docket.
2. HECO is proposing to implement competitive bidding in the three-stage process described in its Final Statement of Position, Exhibit II, Section 1, on page 2. Implementation of competitive bidding must be carefully integrated with the IRP process. HECO anticipates that the Commission will provide guidance in its Decision and Order in the instant docket on the manner in which competitive bidding should be integrated with the IRP process based on a consideration of the positions of each party to the docket. (Please see HECO's Final Statement of Position, Exhibit II, Section 6.a., on pages 34 to 36, for a comparison of the positions of HECO, the CA and HREA on

integration of the competitive bidding process with the IRP process.) The Commission has not yet set a schedule for the fourth round of the HECO IRP. Where the implementation of competitive bidding falls with respect to the timeline for the fourth round of HECO IRP remains to be seen.

HREA-HECO-FIR-15

Referring to paragraph 2 on page 5 of Exhibit II, please explain the difference between "any mandated competitive bidding process" and "another competitive procurement process."

HECO Response:

HECO's position on the implementation of competitive bidding is given in HECO's Final SOP, Exhibit II, Section 1, pages 1 and 2. HECO's proposal for a multiple stage competitive bidding process is given in Exhibit I, pages 31 to 38. The competitive bidding process will become "mandated" if the Commission determines that a competitive bidding process must be used to acquire or build new generating capacity in Hawaii.

With respect to a competitive procurement process, HECO stated in Exhibit II, page 9, of its Final SOP that "The competitive procurement process for distributed generation ("DG") may be different than the competitive procurement process for generation that provides power directly to the utility or sells power to the utility. The competitive procurement procedure that the HECO Companies propose to use for combined heat and power ("CHP") systems that are installed at customer sites was detailed in the generic DG investigation, Docket No. 03-0371. (See HECO SOP, page 3.)" Please see the referenced section in HECO's Final SOP as well as HECO's testimony in the DG investigation, to which HREA was a party.

HREA-HECO-FIR-16

The fourth paragraph on page 14 of Exhibit II reads:

> *"By far the longest part of the process in Hawaii is obtaining the appropriate permits and approvals for new generation. Hawaii has a very limited number of sites that are available to locate new generation, and changing land use designations in Hawaii in order to acquire new generation sites is difficult and time-consuming with an uncertain."*

Given the identified problems in permitting is HECO considering soliciting for small projects in distributed locations? If not, why not?

HECO Response:

Please see HECO's response to HREA-HECO-FIR-2, which discusses the pros and cons of installing smaller sized facilities.

HREA-HECO-FIR-17

Finally, HREA would like to know if HECO is willing to "play by the same rules" as IPPs, if HECO were allowed by the PUC to advance its own proposal in a competitive solicitation. Specifically:

1. Set up a solicitation team, such that HECO's proposal team has no advance information beyond what is released to all potential bidders, e.g., such information as is transmitted in a pre-RFP release briefing?
2. Would HECO pay for its own costs to prepare and submit a proposal, i.e., not propose to have ratepayers reimburse HECO for their proposal costs?
3. If successful, would HECO finance its own project, and like IPPs, be paid based on the delivered capacity and energy like IPPs, i.e., HECO would not rate base its new generation investments with a guaranteed return on that investment?

HECO Response:

1. In HECO's Final SOP, Exhibit II (pages 17-22), HECO discusses a number of steps a utility can take when the utility bids on its own RFP in order to avoid self-dealing or a concern over an unfair competitive advantage that may be perceived by other bidders. As stated in Exhibit II, pages 20 and 21, one of the measures HECO could consider implementing to avoid the appearance of self-dealing or an unfair competitive advantage, as may be perceived by other bidders or stakeholders, when the utility is proposing a self-build option, includes establishing "a separate project team to undertake the bid evaluation, with no team member having any involvement in the utility self-build option. This would serve to mitigate any potential bias towards the utility's own self-build option." However, on page 21, HECO also caution that "While HECO could consider implementing these collective measures, they would not come without a significant investment in time, expense and resources. For example, in undertaking a competitive bidding process, utilities generally establish several internal

project teams for the price analysis, non-price analysis and contract negotiations. This usually requires several analysts to undertake the pricing assessment as well as representatives from a number of departments within the Company to undertake the non-price analysis (e.g. financial analysis, environmental analysis, fuels, engineering, transmission system analysis, operations, siting/land, and legal)." HECO further stated that, "If the utility is proposing a self-build option, available resources may be further limited, or even unavailable, if a separate project team is formed to undertake the bid evaluation, with no team member having any involvement in the utility self-build option. Small utilities, such as HECO, may be particularly constrained in their ability to dedicate the appropriate amount of resources to adequately staff the project teams required. In other words, there are not enough people with the specialized skills to divide into the specific functions needed to carry out bidding and evaluation responsibilities, while at the same time being excluded from carrying out their planning and evaluation responsibilities with respect to the utility's own projects. Such a resource problem has existed for larger utilities, such as Portland General Electric, which presented a challenge for dedicating the required level of staff to the process."

2. If competitive bidding is mandated by the Commission, presumably the cost recovery issues will also be determined by the Commission. The cost of developing and implementing a competitive bidding program as a mechanism to benefit the customer through the solicitation and selection of the best resources should be recoverable by the utility as a cost of doing business.

3. IPPs in Hawaii are not required to "play" by the same rules as utilities. They are not regulated as utilities. The return they can earn is not set or limited by regulation.

HECO's self-build option would be proposed as a cost-of-service option, as HECO and the Consumer Advocate recommend. Utilities subject to cost-of-service regulation are provided with a reasonable opportunity to earn a "fair" return, not with a "guaranteed" return. For a HECO-owned project, HECO (unlike an IPP) would not be permitted to earn an unregulated return on its investment.

It is sometimes argued that a utility should be paid for power on the same basis as an IPP. But what is generally meant is that "bad" outcomes should be borne by shareholders, but "good" outcomes should be retained by ratepayers, since the utility is only entitled to recover its costs. Even when utilities are "promised" that they can retain the results of good outcomes for shareholders, the reality is that regulation tends to be asymmetric in such cases, because the benefit of good outcomes can be taken away indirectly through the regulation of other aspects of the utility's business, or by reinterpreting the "deal" between the utility and itself, since the regulatory agency would retain jurisdiction over all aspects of the utility's operations.

The utility's retention of full and complete control over generation that is owned by the utility and placed in rate base, and the regulatory agency's retention of jurisdiction over rate based assets, also are beneficial from a utility system reliability perspective, and from a regulatory perspective. The utility's only control over the design, operation, maintenance, repair and modification of an IPP-owned generating unit is through the provisions of a PPA, and the regulatory agency's only avenue of review of the IPP's design, operation, maintenance, repair and modification of its unit is through a review of the utility's administration of the PPA. (For example, see FSOP

Exhibit I, pages 4-8.) The purpose of competitive bidding is to obtain benefits for utilities and ratepayers, not to treat utility-owned and IPP-owned generation the same.